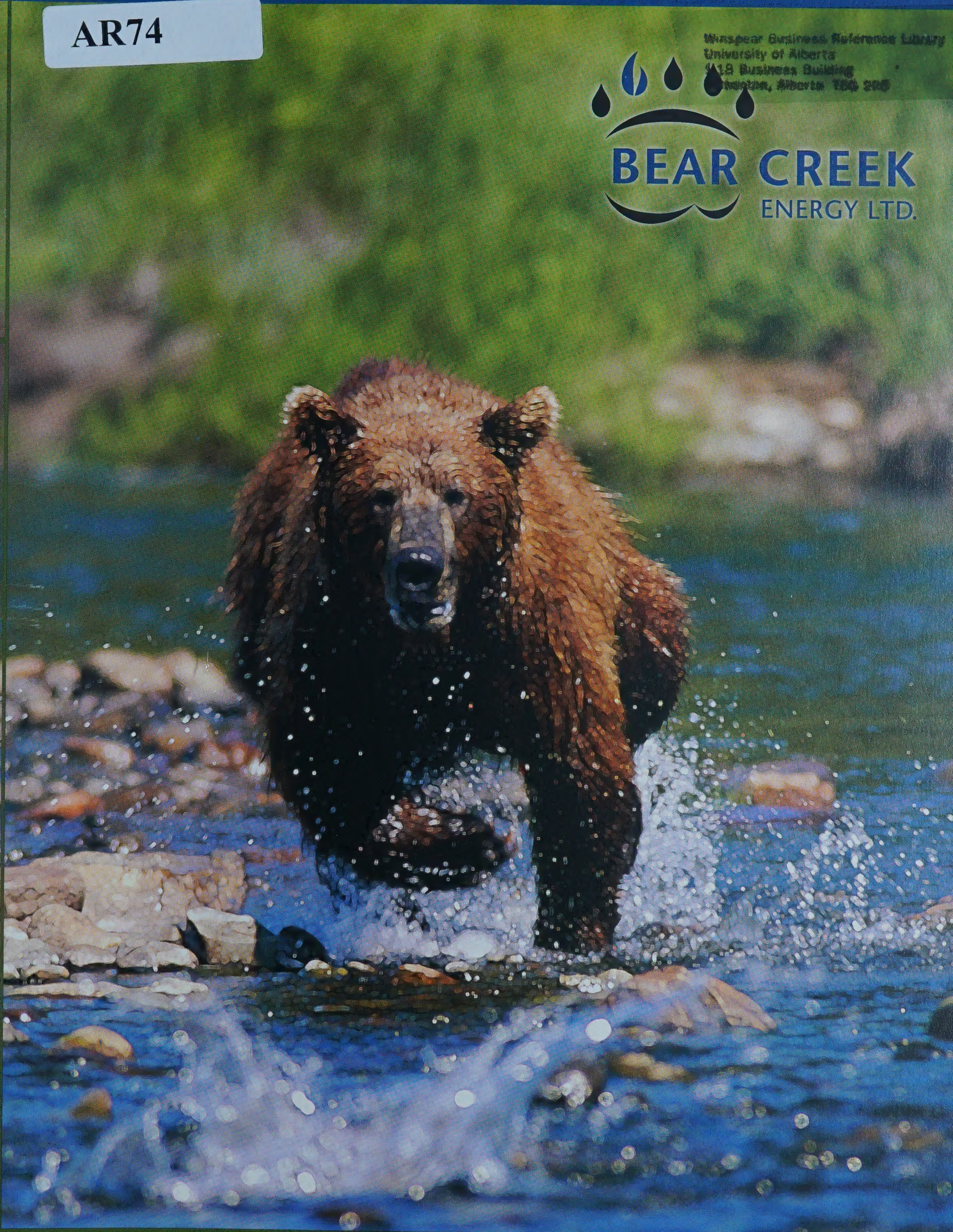
2003 Annual Report

Bear Creek Energy Ltd.

BEAR CREEK ENERGY LTD.



Capturing Value

Corporate Profile

Bear Creek Energy Ltd. was created on July 25, 2003, through the combination of Crossfield Gas Corp. and Millennium Energy Inc. The Company's shares trade on the Toronto Stock Exchange under the symbol "BCK". Our objective is to capture significant Shareholder value through exploration and development, complemented by strategic acquisitions. We focus on high-quality reserves noted for high productivity, reserve life and profitability. The Bear Creek team has a proven track record of building Shareholder value through the drillbit.

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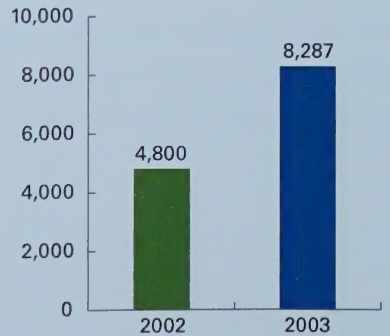
ANNUAL AND SPECIAL MEETING

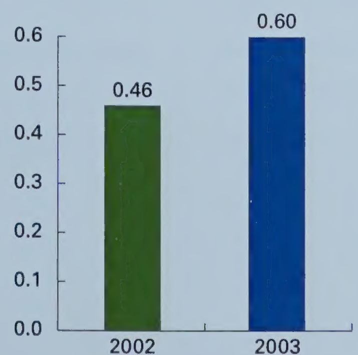
The Company's annual and special meeting is scheduled for 1:30 p.m. on Friday, June 11th, 2004, at the Westin Hotel in the Barclay Room, located at 320 - 4th Avenue S.W. Calgary, Alberta.

Financial & Operating Highlights

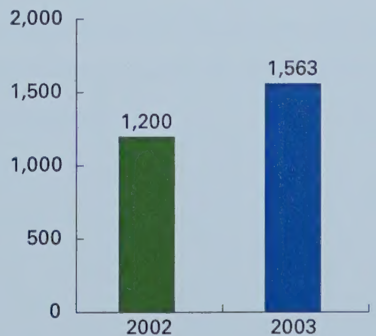
	Three Months Ended			Twelve Months Ended		
	Dec. 31, 2003	Dec. 31, 2002	% Change	Dec. 31, 2003	Dec. 31, 2002	% Change
Financial ($ thousands, except per share amounts)						
Petroleum and natural gas sales	5,401	4,229	28	20,773	12,815	62
Cash flow from operations	2,056	1,743	18	8,287	4,800	73
Per common share – basic	0.13	0.14	(7)	0.60	0.46	30
Per common share – diluted	0.12	0.14	(14)	0.59	0.46	28
Net earnings	(319)	188	(269)	1,259	548	130
Per common share – basic	(0.02)	0.02	(200)	0.09	0.05	80
Per common share – diluted	(0.02)	0.02	(200)	0.09	0.05	80
Capital expenditures	9,757	7,839	25	26,697	18,454	45
Working capital deficit (including bank debt)	(11,925)	(11,420)	4	(11,925)	(11,420)	4
Common shares outstanding (millions)	17.0	12.2	39	17.0	12.2	39
Weighted average shares outstanding (millions)	16.3	12.2	34	13.8	10.4	33
Operating						
Average daily production						
Natural gas (mcf/d)	4,455	2,816	58	4,030	2,354	71
Oil (bbls/d)	771	715	8	669	647	3
NGL's (bbls/d)	243	166	46	222	161	38
Barrels of oil equivalent (boe/d 6:1)	1,757	1,350	30	1,563	1,200	30
Average prices						
Natural gas ($/mcf)	5.92	5.42	9	6.66	4.17	60
Oil ($/bbl)	31.27	35.36	(12)	33.32	32.54	2
NGL's ($/bbl)	33.77	32.66	3	35.04	26.35	33
Operating netback ($/boe)	18.88	17.26	9	20.52	16.10	27
Wells drilled						
Gross	20	9	122	33	19	74
Net	9	7.6	18	14.9	16.3	(9)



Cash Flow From Operations
($000s)

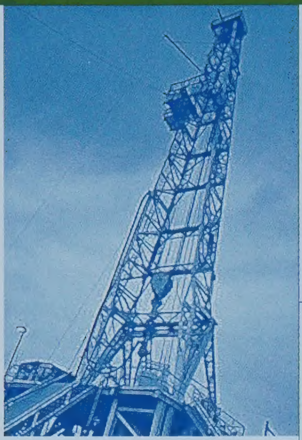


Cash Flow Per Share
($/share)



Average Daily Production
(boe/d)

Report to Shareholders



Bear Creek is a growth-oriented exploration and production company with a clear objective of capturing significant Shareholder value through the drillbit.

The past year was marked by the Company's transition into the public market, major accomplishments in our exploration program, solid financial results and key additions to our executive and technical team. I am confident that our high-quality asset base, strong prospect inventory and talented team will enable us to meet our objective of capturing significant growth in Shareholder value in 2004 and beyond.

We set three key objectives for 2003:

1. Access public markets to facilitate funding of an expanded capital program;
2. Establish new operating areas to provide additional core area growth potential;
3. Continue our focus on per share growth to preserve and build Shareholder value.

We met each of these objectives. A "going public" transaction was successfully completed and Bear Creek commenced trading on the Toronto Stock Exchange under the symbol "BCK" on August 6, 2003. The $12 million in new equity raised during the year allowed us to conduct a $21 million exploration program. An additional $12 million was raised in the first quarter of 2004 to strengthen our balance sheet and enabled us to expand our 2004 capital program to $30 million.

Our exploration program continued to deliver successful results at our Westerose core property and established new production in the Brazeau, Sakwatamau and Hazelwood areas. Although these new areas accounted for only minor production and reserve growth in 2003, all three provide meaningful growth opportunities and have the potential to develop into core assets.

We grew production to 1,900 boe at year-end with an additional 500 boe to be brought onstream in 2004. Growth in production volumes and high commodity prices contributed to strong financial results. We generated cash flow of $8.3 million and earnings of $1.3 million. Cash flow increased 73%, or 30% on a per share basis, and earnings rose 130%, or 80% per share.

CAPTURING VALUE

Our business plan is to capture Shareholder value through the drillbit, complemented by strategic acquisitions that establish new core operating areas or enhance existing properties. We focus on higher-quality, multi-zone natural gas and light oil projects in West Central Alberta and maintain a balanced portfolio of lower-risk to high-impact drilling opportunities in our exploration program. The Bear Creek team has a proven track record of creating significant Shareholder value using this drillbit growth strategy over the past 10 years.

Our successful 2003 exploration program has set up a number of lower-risk development projects that should contribute significant production gains in 2004.

We invested $21 million in our exploration and development program and drilled 33 gross (14.9 net) wells with a 79% success rate. We spent $13.5 million on drilling and completions, $2.6 million on land and seismic and $3.8 million on facilities and workovers. Our 2003 exploration program delivered solid results by:

> Extending our corporate reserve life index to 7.2 years on a proved reserve basis and 9.3 years for proved plus probable reserves;

> Growing proved reserves by 37% and proved plus probable reserves by 45%;

> Replacing our 2003 production by 321% on a proved reserve basis and 456% on proved plus probable reserves.

2003 EXPLORATION HIGHLIGHTS

Westerose has grown into a true cornerstone asset and contributed 94% of Bear Creek's 2003 production and 87% of our year-end proved reserves. The property is located in our focus West Central region and offers multi-zone natural gas and light oil potential, year-round access and lower- cost gas plant infrastructure.

Our Westerose drilling program was highlighted by two 100% interest natural gas discoveries. These new wells accounted for a meaningful 663 mboe of proved reserve additions. Our 16-8 Mannville gas discovery averaged 220 boe per day during the first quarter of 2004 and our 11-25 Banff gas discovery is expected to be onstream in the fourth quarter. Additional drilling activity is planned to follow up on these new discoveries.

Bear Creek discovered a new Mississippian light oil pool in the Hazelwood area of Southeast Saskatchewan in 2003. We own a 40% interest in this new pool and had four wells on stream by year-end. A new battery is nearing completion and we have commenced a multi-well vertical and horizontal drilling program to fully develop the pool.

2004 EXPLORATION HIGHLIGHTS

Bear Creek announced a significant new light oil pool discovery in the first quarter of 2004 at Sakwatamau in our West Central focus region. The 11-16 discovery well flowed at rates exceeding 600 barrels of light oil per day during an initial four-day test period and produced its allowable 15,000 bbls within a 25-day period at an average rate of 600 bbls per day. The 11-16 well will be restricted to 60 bbls per day until the pool is delineated and we receive GPP or secondary recovery approval. Bear Creek owns a 100% interest in the 11-16 well and has interests ranging from 60 to 100% in several offsetting sections. We plan to commence a development drilling program in the second quarter.

Our 2004 exploration program is off to a strong start and we are well positioned to capture new opportunities in this encouraging growth environment.

OUTLOOK

Having increased our 2004 capital budget to $30 million, we are forecasting production growth to 3,500 boe per day by year-end. We are pleased with the depth, diversity and risk/reward potential of our 2004 drilling program and are excited about the early success of this year's program. We continue to generate new drilling opportunities on our existing land base and expect to add to our inventory of undeveloped lands and new prospects over the course of the year.

Since our current and forecast production mix is equally weighted to natural gas and light oil, we benefit from historically higher pricing for both oil and natural gas. On the basis of current market fundamentals, we expect commodity prices for both products will remain higher than historical averages.

The junior oil and gas sector has delivered tremendous growth over the past two years. Experienced management teams with proven technical expertise continue to capture growth opportunities that do not meet the risk/reward thresholds of senior producers or royalty trusts. Access to capital markets and strong commodity prices have also fuelled strong growth in the junior sector. We believe Bear Creek has all the ingredients to thrive in this environment.

Bear Creek has made great strides in 2003 and I would like to thank our Shareholders, Board of Directors and our talented and dedicated team for their support and efforts.

Russell J. Tripp
President and Chief Executive Officer

Exploration & Operations Review

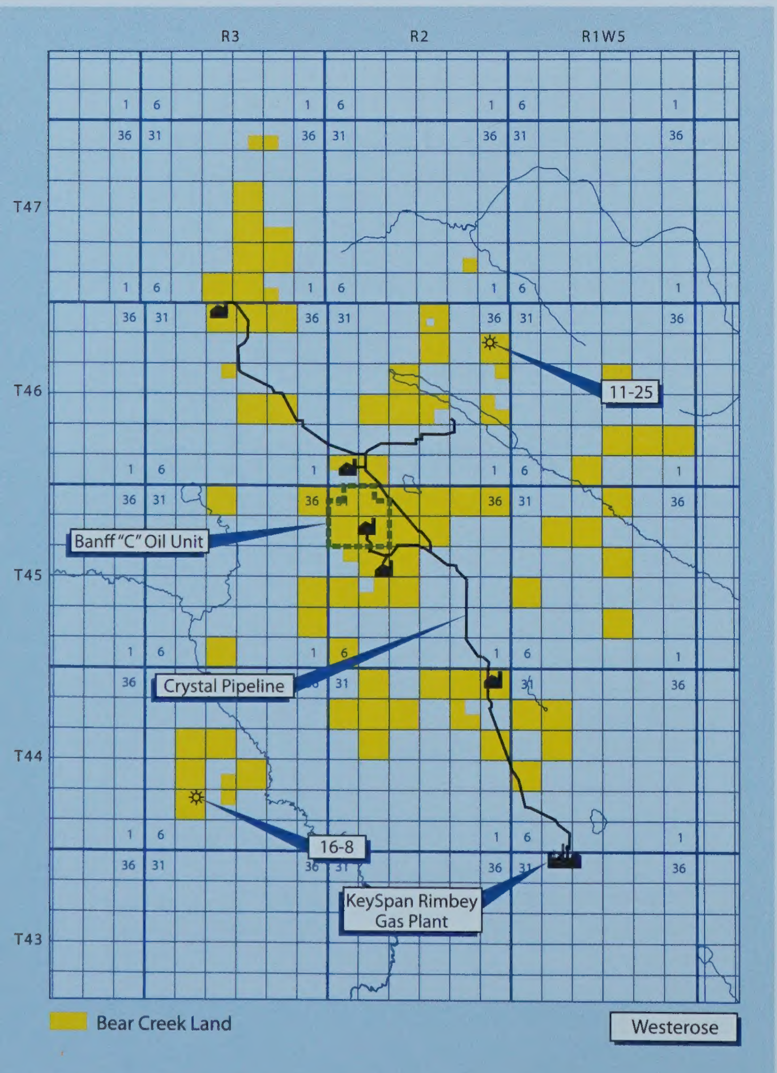
Our exploration program is focused in West Central Alberta and our primary drilling targets are Mississippian to Cretaceous reservoirs noted for their high productivity, reserve life and profitability. We maintain a portfolio of low to medium risk wells and high impact "growth acceleration" wells to balance risk with growth targets.

Westerose/Garrington, Brazeau/Ferrier and Sakwatamau/Goodwin are located in our West Central Alberta focus region and the Hazelwood area in Southeast Saskatchewan is an emerging focus area. Westerose/Garrington is our dominant asset base with approximately 86% of the Company's reserves and 82% of production. The remaining three areas of operations are the result of internally-generated exploration concepts that have established new producing areas for the Company, each of which has the potential to grow into a significant property.

We are confident that our drillbit growth strategy and our strategic focus on natural gas and light crude oil will provide sustainable and profitable growth for Shareholders.

Central & West Central Alberta

Westerose/Garrington > The Westerose/Garrington area has grown into Bear Creek's main producing area since our initial acquisition in the area in December, 2001. The area is noted for year-round access, multi-zone potential, high-quality long life natural gas and light oil reserves and abundant infrastructure and processing capacity. The primary drilling targets are Mississippian carbonates and Cretaceous sandstones at depths ranging from 500 metres to 2,300 metres. Seismic has been a successful exploration and development tool in this area and Bear Creek owns and/or has access to extensive 2-D and 3-D coverage.



WESTEROSE

The Westerose property is approximately 64 kilometres southwest of Edmonton and is comprised of 59,091 acres (41,795 net) of which 26,797 acres (24,706 net) were undeveloped at the end of 2003.

Bear Creek operates approximately 53% of its total sales production in Westerose, which includes predominantly all its natural gas properties. Bear Creek also operates five compressor stations and 80 kilometres of pipeline gathering facilities that are connected to the KeySpan Rimbey gas plant.

At the end of 2003, the Westerose property produced 1,265 boe/d comprised of 3.3 mmcf/d of sales gas, 566 bbl/d of oil and 149 bbl/d of natural gas liquids. The Company drilled 12 gross wells (4 net) at Westerose in 2003. Our Westerose exploration program was highlighted by two significant 100% working interest gas discoveries. The 16-8-44-02W5 well was completed late in the year as a new pool discovery and has been producing at a restricted rate of approximately 2 mmcf/d during the first quarter 2004. The 11-25-46-02W5 well was successful in extending the Pembina Banff "D" Gas Pool and is expected to be tied in during the fourth quarter 2004. Follow-up locations for both the 16-8 and 11-25 gas discoveries are planned for 2004.

WESTEROSE SOUTH BANFF "C" OIL UNIT

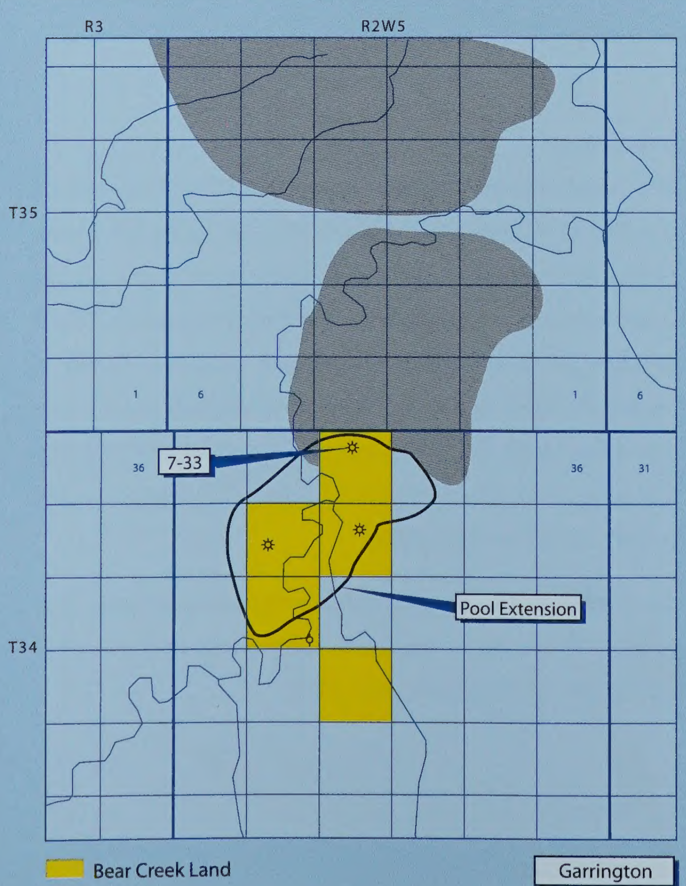
The Westerose South Banff "C" Oil Unit is located within the Westerose area. Bear Creek holds a 46% working interest in the Banff "C" Unit, which was estimated by GLJ at 31 million barrels of original oil in place. Cumulative production for the unit was 2.65 million barrels of original oil (8.5% recovery of original oil in place) at December 31, 2003. The reservoir in the Banff "C" Unit is a carbonate that is conducive to secondary recovery through waterflooding based on analogous pools and engineering studies completed on the unit. Waterflood operation commenced in the Banff "C" Unit during 2003 with the benefit of the waterflood response expected to be realized in 2004. GLJ has estimated that as of December 31,

2003, Bear Creek had 2.00 mmboe (which equates to a 20% recovery factor) of proven reserves and 2.43 mmboe (which equates to a 23% recovery factor) of proven and probable reserves booked to the Banff "C" Unit. Bear Creek expects that the combination of waterflood response and infill drilling supported by our proven seismic model will add incremental reserves over and above current GLJ estimates.

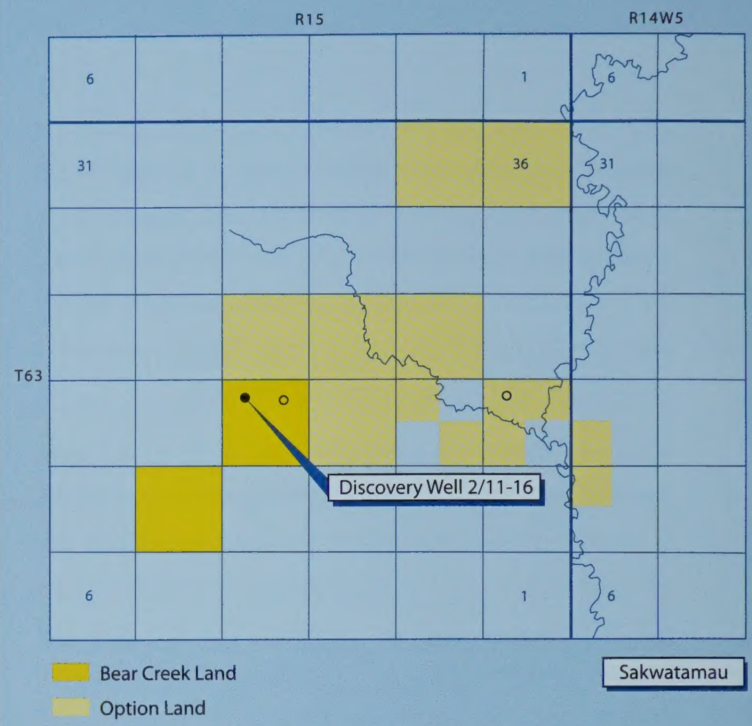
At the end of 2003, the unit consisted of two down-dip water injectors and seven oil wells on 160-acre spacing producing at a rate of 1,190 boe/d gross (546 boe/d net) of 27 degree API oil. Since then, the unit drilled a third water injector and two new infill oil wells on 80-acre spacing. These new wells will increase production once GPP is approved. Additional infill drilling is planned for 2004 and 2005.

GARRINGTON

The Garrington property is approximately 54 kilometres north of Calgary. Bear Creek holds working interests in a total of 3,200 acres (1,280 net) of which 1,920 acres (720 net) were undeveloped lands at the end of 2003. The property is the south extension of the Innisfail Pekisko "E" gas pool and was established as a new producing area for Bear Creek with the drilling of the 7-33-34-2W5 horizontal well in the first quarter of 2003. Bear Creek drilled a total of three gross horizontal (1.25 net) wells in 2003. At the end of 2003, Bear Creek had one producing horizontal well on this property producing at a rate of 1.7 mmcf/d gross sales gas (850 mcf/d net) and 124 bbl/d of natural gas liquids (62 bbl/d net) with one well waiting on tie-in. Two gross (0.62 net) wells were drilled in the first quarter 2004 with one of these wells producing at approximately 500 mcf/d gross (187 mcf/d net) and one standing cased.



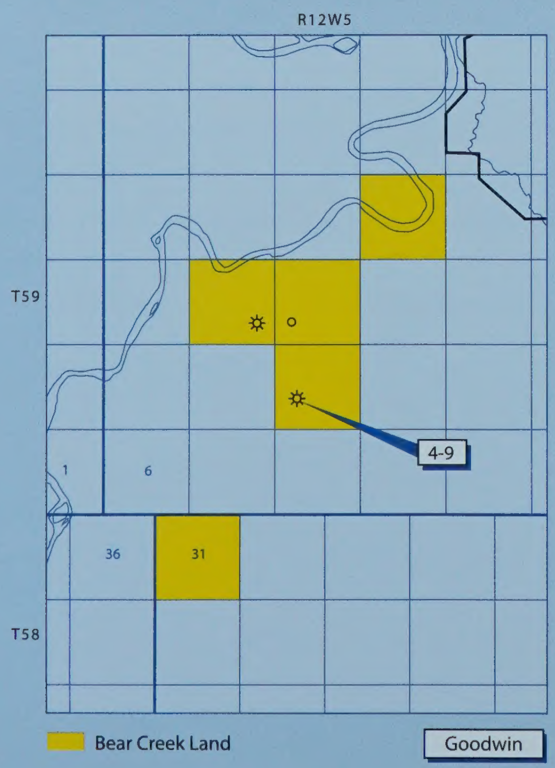
Sakwatamau/Goodwin > The Sakwatamau/Goodwin area was established as a new natural gas and light oil exploration focus region for Bear Creek in 2003. The area has year-round access with multi-zone potential and available Crown lands and infrastructure. The primary drilling targets are Cretaceous sandstones at depths between 1,000 metres and 2,000 metres. Bear Creek has access to extensive 2-D and 3-D seismic data throughout this region.



SAKWATAMAU

The Sakwatamau property is approximately 120 kilometres northwest of Edmonton. Bear Creek owns high working interests in 3,200 acres (2,900 net) and has an additional 4,960 acres under option.

Bear Creek drilled a significant light oil pool discovery in the first quarter 2004 at 2/11-16-63-15W5 and established Sakwatamau as a new producing property. The 2/11-16 well flow tested in excess of 600 bbl/d of light sweet oil during a four-day test period and produced its allowable of 15,000 barrels within 25 days at an average rate of 600 bbl/d. The well is now restricted to a rate of 60 bbl/d. A development drilling program is scheduled to start in the second quarter of 2004 to delineate the new pool and obtain GPP or secondary recovery (waterflood) approval to maximize production rates and recoverable reserves. Bear Creek owns a 100% interest in the discovery well and 60 to 100% interest in adjacent sections.

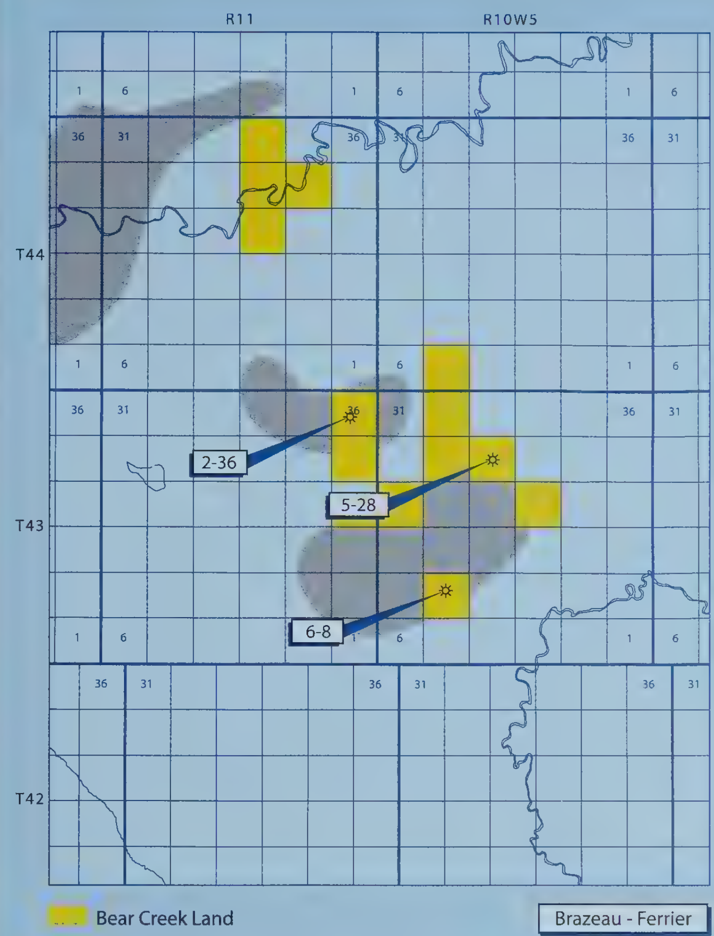


GOODWIN

Bear Creek has working interest in 1,920 acres (1,280 net) in the Goodwin area approximately 87 kilometres northwest of Edmonton. The Goodwin area offers low to medium risk, multi-zone oil and gas potential. The property was established as a new producing area for Bear Creek with the drilling of the 4-9-59-12W5 well in the fourth quarter 2003. The 4-9 well was successfully completed as a dual zone gas well and was placed on production at a rate of 2.1 mmcf/d of gas gross (525 mcf/d net) in December, 2003.

Bear Creek shot a new 2-D seismic program on this property to identify additional locations and plans to drill an offset well at 50% working interest in 2004.

Brazeau/Ferrier > The Brazeau/Ferrier area offers multi-zone gas targets in Mississippian, Jurassic and Cretaceous reservoirs at depths of 2,000 metres to 3,000 metres.



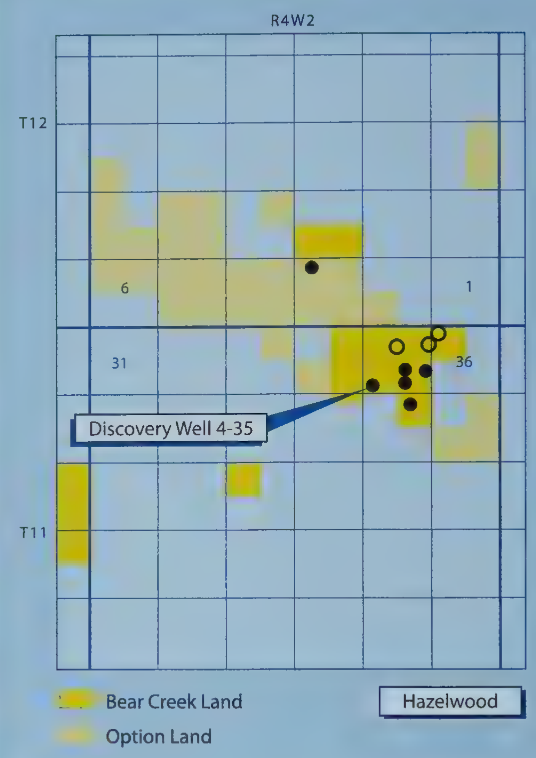
BRAZEAU

The Brazeau property is approximately 72 kilometres southwest of Edmonton. At the end of 2003, Bear Creek held working interests in a total of 1,920 gross acres (1,280 net) of undeveloped lands and had approximately 4,800 gross acres of land under farm-in. We own 48 square kilometres of 3-D seismic and have access to extensive 2-D coverage over the area.

Bear Creek drilled one well in 2003 and two wells in the first quarter 2004, all of which are successful gas wells. This area was established as a new producing area for Bear Creek with the drilling of the 5-28-43-10W5 well in the first quarter 2004, which is on production at approximately 500 mcf/d gross (250 mcf/d net) from the Jurassic Rock Creek. Bear Creek followed this well with a successful gas well at 2-36-43-11W5 in the Mississippian Elkton and a dual zone gas well at 6-8-43-10W5. Additional drilling and recompletion operations are planned for the Brazeau region in 2004.

Southeast Saskatchewan

Southeast Saskatchewan > This emerging area exposes Bear Creek to low-risk, light oil targets and production. The area has year-round access with drilling depths of 1,000 metres to 1,500 metres targeting Mississippian reservoirs. Bear Creek discovered a new light oil pool in the Tilston Formation at Hazelwood in 2003.



HAZELWOOD

The Hazelwood property is approximately 100 kilometres southeast of Regina. Bear Creek has working interest in a total of 3,207 acres (1,010 net) of which 3,006 acres (941 net) were undeveloped at the end of 2003. The 4-35-11-4W2 discovery well was drilled based on 2-D seismic data and encountered a new Mississippian Tilston oil pool. Following this success, a six square kilometre 3-D program was shot over the property. Bear Creek drilled three (1.2 net) successful light oil wells in 2003 with initial production of approximately 520 bbl/d gross (210 bbl/d net) and, as expected, high water cuts. A 6,500 barrel per day oil battery and facilities have been installed. During the first quarter 2004, Bear Creek drilled two additional wells (0.8 net) in this seismic feature and plans to drill three more vertical delineation wells before moving into a horizontal development well program.

During the first quarter 2004, Bear Creek drilled a second new pool discovery in the Mississippian Tilston on a separate seismic feature. We shot an additional 16 square kilometre 3-D seismic program to define this new pool and evaluate additional prospects on offsetting land. Bear Creek owns a 50% interest in the discovery well, 1,560 acres of freehold lands and has an additional 5,600 acres under option offsetting this new discovery.

Management's Discussion & Analysis

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and notes for the years ended December 31, 2003 and 2002. The Management's Discussion and Analysis was prepared as of March 31, 2004.

Basis of Presentation – The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles. The reporting and the measurement currency is the Canadian dollar.

Non-GAPP Measurements – The Management's Discussion and Analysis contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles as an indicator of the Company's performance. Bear Creek's determination of cash flow from operations may not be particularly comparable to that reported by other companies, especially those in other industries. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows in the audited consolidated financial statements. The Company also presents cash flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Boe Presentation – The term barrels of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in the report are derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas revenues increased 28% to $5.4 million for the three months ended December 31, 2003, as compared with $4.2 million for the same period in 2002. This increase was a result of increased sales volumes and increased natural gas and NGL prices. Gas volumes increased by 58% to 4.5 mmcf/d from 2.8 mmcf/d in 2002. Oil volumes increased to 771 bbl/d from 715 bbl/d and NGL's were up to 243 bbl/d for a 46% increase over the 166 bbl/d from the fourth quarter of 2002. The increased volumes were a result of drilling that focused on gas opportunities in the Westerose and Garrington areas and properties from the Millennium acquisition. For the 12-month period ended December 31, 2003, gas volumes were up 71% to 4.0 mmcf/d while oil volumes were up 3% and NGL's were up 38% compared with the year ended December 31, 2002.

	Three Months Ended December 31			Twelve Months Ended December 31		
Average daily production volumes	2003	2002	% Change	2003	2002	% Change
Natural gas (mcf/d)	4,455	2,816	58	4,030	2,354	71
Oil (bbl/d)	771	715	8	669	647	3
NGL's (bbl/d)	243	166	46	222	161	38
Total (boe/d)	1,757	1,350	30	1,563	1,200	30

Prices for natural gas increased to $5.92 per mcf in the fourth quarter from $5.42 in the same quarter of 2002. Oil prices were down to $31.27 per bbl compared with $35.36 for the fourth quarter of 2002, while NGL's were up 3% to $33.77 per bbl compared with $32.66 in 2002. These prices are net of hedge transactions in the fourth quarter of 2003 of $186,825 for oil or $2.64 per bbl as compared with $90,812 or $1.39 per bbl in 2002. These contracts are used as a method to provide downside protection for our cash flow.

See Note #9 for current hedging summary. For the 12 months ended December 31, 2003, gas prices were up 60% to $6.66 per mcf compared with the first 12 months of 2002. Oil prices were up 2% to $33.32 per bbl while NGL's prices increased 33% to $35.04 per bbl compared with the first nine months of 2002.

During the fourth quarter, the Company had forward price arrangements on 250 bbl/d for oil at $US 25.67 WTI that expired at the end of 2003, and had sold 1,000 mcf/d of gas into a collar providing a floor of $4.50 and a ceiling of $6.00 per mcf that expired at the end of October, 2003.

	Three Months Ended December 31		Twelve Months Ended December 31	
Average prices per unit of production	2003	2002	2003	2002
Gas				
Gross $/mcf (before hedge)	5.92	5.42	6.81	4.17
Hedge gain (loss) $/mcf	–	–	(0.15)	–
Net $/mcf	5.92	5.42	6.66	4.17
Oil				
Gross $/bbl (before hedge)	33.91	36.74	36.23	34.05
Hedge gain (loss) $/bbl	(2.64)	(1.38)	(2.91)	(1.51)
Net $/bbl	31.27	35.36	33.32	32.54
NGL's				
Gross $/bbl (before hedge)	33.77	32.66	35.04	26.35
Hedge gain (loss) $/bbl	–	–	–	–
Net $/bbl	33.77	32.66	35.04	26.35

CASH FLOW AND NET INCOME

The Company generated cash flow from operations of $2.1 million ($0.13 per share) in the fourth quarter of 2003 compared with $1.7 million ($0.14 per share) in the fourth quarter of 2002. The increased cash flow for the comparative quarters of 2003 is a result of higher natural gas prices and strong production increases. For the 12 months ended December 31, 2003, the Company generated cash flow from operations of $8.3 million ($0.60 per share) compared with $4.8 million ($0.46 per share) in the prior year as a result of increased production and pricing.

The Company recorded a net loss of $(0.3) million in the fourth quarter of 2003 compared with a gain of $0.2 million in the fourth quarter of 2002. The loss recorded in the fourth quarter is a result of increased G&A expense, future tax expense, and DD&A expenses. Net income for the 12 months ended December 31, 2003, rose 130% to $1.3 million ($0.09 per share) compared with $0.5 million ($0.05 per share) for the same prior year period partially as a result of lower tax rates.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2003	2002	% Change	2003	2002	% Change
Cash Flow – per share						
Basic	$ 0.13	$ 0.14	(7)	$ 0.60	$ 0.46	30
Fully diluted	$ 0.12	$ 0.14	(14)	$ 0.59	$ 0.46	28
Net Income – per share						
Basic	$ (0.02)	0.02	(200)	$ 0.09	$ 0.05	80
Diluted	$ (0.02)	0.02	(200)	$ 0.09	$ 0.05	80

ROYALTIES

Royalties for the fourth quarter of 2003 were $1.0 million compared with $1.4 million in the fourth quarter of 2002. Notwithstanding increased sales in the fourth quarter of 2003, prior quarters royalty expenses booked in the fourth quarter of 2002 disproportionately increased royalties versus sales. Royalties in the fourth quarter of 2003 were reduced as the result of a reclassification of a well by the EUB resulting in a one-time credit to the Company in the amount of $342,000. For the 12 months ended December 31, 2003, net royalties of $5.0 million represent 24% of revenues compared with $3.2 million (25% of revenues) in 2002. The higher gas sales price drives a higher royalty rate that is partially offset by ARTC recovery. ARTC of $310,658 for 2003 is netted from the total royalty expense, while no ARTC was booked for 2002.

	Three Months Ended December 31			Twelve Months Ended December 31		
Royalty Category	2003	2002	% Change	2003	2002	% Change
Crown	249,859	797,326	(69)	3,238,401	2,364,503	40
Freehold	434,891	497,532	(13)	1,121,547	589,795	90
Override	134,123	91,560	46	580,429	265,925	118
ARTC	(70,596)	–	–	(310,658)	–	–
FH tax	266,667	–	–	296,618	–	–
Total Royalty	1,014,944	1,386,418	(27)	5,020,247	3,220,223	56

OPERATING EXPENSES

Operating expenses for the fourth quarter of 2003 were $1,334,956 compared with $698,642 for the fourth quarter of 2002. On a per unit basis, the 2003 cost is $8.26 per boe compared with the fourth quarter of 2002 which was $5.64 per boe. For the 12 months ended December 31, 2003, operating costs totalled $4.0 million ($7.10 per boe) compared with $2.5 million ($5.81 per boe) for the same period of 2002. Per unit costs increased as a result of higher overall industry operating costs and one-time turnaround costs associated with our Westerose facilities and reduced sales volumes at our Westerose property associated with the Rimbey gas plant turnaround. After taking into consideration one-time costs and the reduced sales associated with the Rimbey gas plant turnaround of approximately $0.80 per boe, 2003 operating costs would have been reduced to approximately $6.30 per boe. Operating costs for 2004 are expected to be at or lower than this adjusted rate.

OPERATING NETBACK

The operating netback for the three months ended December 31, 2003, of $18.88 per boe compared with the same period in 2002 of $17.25, is up 9% mainly as a result of reduced royalty expense. For the 12 months ended December 31, 2003, the Company realized operating netbacks of $20.52 per boe, a 27% increase over the $16.10 per boe for the comparable 2002 period, mainly as a result of increased sales prices.

	Three Months Ended December 31			Twelve Months Ended December 31		
Operating Netback ($/boe)	2003	2002	% Change	2003	2002	% Change
Sales price	33.42	34.05	(2)	36.42	29.26	24
Royalties	(6.28)	(11.16)	(44)	(8.80)	(7.35)	20
Operating expense	(8.26)	(5.64)	46	(7.10)	(5.81)	22
Operating netback	18.88	17.25	9	20.52	16.10	27

GENERAL AND ADMINISTRATIVE EXPENSES

Bear Creek has not capitalized any G&A in 2003 or 2002. For the three-month period ended December 31, 2003, the Company had net G&A expenses of $939,375 (including $74,705 for stock-based compensation expense, see Note #6) compared with $306,062 for same prior year period. On a per unit basis, the costs in the fourth quarter of 2003 were $5.81 per boe compared with 2002 costs of $2.46 per boe. Increased levels of activity and expanding capital programs have increased our staff count and administrative costs. For the 12 months ended December 31, 2003, the Company recorded G&A expenses of $2,894,123 ($5.07 per boe) compared with $1,734,569 ($3.96 per boe) for the same period in 2002. After taking into consideration a one-time expense of $400,000 in the first quarter that increased costs by $0.70 per boe, G&A costs per boe were $4.37 in 2003. The Company currently has 14 employees and is positioned to handle the increased capital programs planned for 2004. We expect G&A costs per boe to be reduced in 2004 in conjunction with forecast production increases.

	Three Months Ended December 31			Twelve Months Ended December 31		
G&A Expense ($)	2003	2002	% Change	2003	2002	% Change
G&A expense (gross)	1,005,366	423,368	137	3,209,280	1,985,762	62
Overhead recoveries	(65,991)	(117,306)	(44)	(315,157)	(251,193)	25
G&A expense (net)	939,375	306,062	206	2,894,123	1,734,569	67
G&A expense $/boe (net)	5.81	2.46	136	5.07	3.95	28

INTEREST EXPENSE

In the three-month period ended December 31, 2003, the Company recorded an interest expense of $105,231, an increase from $74,896 in the fourth quarter of 2002. The increase is a result a higher draw on our operating bank line. Interest for the first 12 months of 2003 was $506,933 compared with $421,471 for the same 2002 period as a result of higher bank debt.

DEPLETION, DEPRECIATION AND AMORTIZATION (DD&A)

Depletion and depreciation in the fourth quarter of 2003 was $1.9 million compared with the fourth quarter of 2002 which was $1.4 million for a 35% increase. For the year ended December 31, 2003, the total expense was $6.8 million or a 69% increase compared with the full year 2002 of $4.1 million. On a per boe basis, the fourth quarter 2003 was $11.95 per boe compared with the fourth quarter 2002 amount of $11.58 per boe. On a full-year basis, the boe rate was up 29% for 2003 at $11.96 per boe compared with the 2002 rate of $9.27 per boe.

Site restoration costs for the three months ended December 31, 2003, were $40,000 (0.27 per boe) compared with the same period of 2002 which were $33,307 (0.27). For the year ended December 31, 2003, site restoration costs were $135,725 (0.24 per boe) compared with $107,652 (0.25 per boe) for the year ended December 31, 2002.

	Three Months Ended December 31			Twelve Months Ended December 31		
($)	2003	2002	% Change	2003	2002	% Change
Depletion and depreciation	1,938,917	1,434,181	35	6,838,979	4,057,194	69
Site restoration	40,000	33,307	20	135,725	107,652	26
Cost per boe						
Depletion and depreciation	11.95	11.58	3	11.96	9.27	29
Site restoration	0.25	0.27	(7)	0.24	0.25	(4)

TAXES

For the three-month period ended December 31, 2003, the Company recorded a current tax expense of $31,557 and future tax expense of $321,743 compared with the $18,702 current tax expense and $87,810 future tax expense recorded in the fourth quarter of 2002. The current tax expense is comprised only of large corporation tax that is a capital-based tax, and the Company did not pay any current income taxes for 2003. For the 12-month period ended December 31, 2003, the Company recorded a current tax expense of $97,942 and a future tax benefit of $21,652. Future tax for the period ended December 31, 2003, includes favourable tax rate changes effect of $687,688.

During 2003, the Company issued 1,210,962 flow-through shares for $6,090,015. In accordance with the agreements between the Company and the flow-through Shareholders, the Company renounced $6,090,015 of Canadian Cumulative Exploration Expense as of December 31, 2003. This renunciation gave rise to a future tax liability of $2,482,092. It is estimated that $2,590,015 of the expenses had been incurred by December 31, 2003, with the remaining $3,500,000 to be incurred during 2004.

Bear Creek had the following income tax pools available at January 1, 2004:

	($000s)
Non-capital losses	2,233
Canadian exploration expense	558
Canadian development expense	7,932
Canadian oil and gas property expenses	22,553
Undepreciated capital costs	8,419
Financing costs	1,203
Other	155
	43,053

CAPITAL EXPENDITURES

During the fourth quarter of 2003, the Company drilled 20 (9.0 net) wells resulting in 9 (3.1 net) gas wells, 4 (1.7 net) oil wells, 1 (0.5 net) service well, 2 (1.25 net) standing wells and 4 (2.5 net) dry and abandoned wells for a 70% success rate. Capital expenditures during the fourth quarter of 2003 increased to $9.8 million from the $7.8 million incurred in the comparable 2002 period. During the 12 month period ended December 31, 2003, the Company drilled 33 (14.9 net) wells with a 79% success ratio resulting in 16 (6.2 net) gas wells, 9 (3.5 net) oil wells, 1 service well, 2 (1.25 net) standing wells and 5 (3.5 net) dry and abandoned wells. During the same period, the Company incurred capital expenditures of $19.9 million compared with $18.5 million for the 12-month period in 2002. In addition, the Company has recorded $6.8 million for the July acquisition of Millennium. A summary of our expenditures for the three-month and 12-month periods ended December 31 for 2003 and 2002 is as follows:

	Three Months Ended December 31			Twelve Months Ended December 31		
Capital expenditures ($000s)	2003	2002	% Change	2003	2002	% Change
Land acquisitions	529	693	(24)	1,542	4,946	(69)
Geological & geophysical	321	494	(35)	1,129	843	34
Drilling & completions	7,705	5,323	45	13,479	10,371	31
Equipment & facilities	1,167	1,291	(10)	3,756	2,228	69
Other	33	36	(15)	32	120	(73)
Corporate acquisition	2	–	–	6,759	–	–
Total capital expenditures	9,757	7,840	82	26,697	18,454	45

RESERVES

The corporate reserves dated January 1, 2004, were evaluated by the independent engineering firm of Gilbert Laustsen Jung Associates Ltd. ("GLJ") in accordance with the definitions set out under National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Total proved reserves as at December 31, 2003, increased 38% to 4.65 million boe compared with 3.37 million boe as at December 31, 2002. Total proved plus probable reserves at December 31, 2003, increased 45% to 5.9 million boe compared with 4.1 million boe at December 31, 2002.

COMPARABILITY OF RESERVE INFORMATION

The change to proved and probable reserve definitions implemented by NI 51-101 for the year ended December 31, 2003, may make reserve quantity and value comparisons to prior years difficult. The proved plus risked probable reserves ("established reserves") presented for 2002 and prior years, which were calculated under National Policy 2B, were considered to be a reasonable estimate of the reserves that would actually be recovered and, as a result, are comparable with the proved plus probable reserves calculated under NI 51-101. For the 2003 presentations, where comparisons of the 2003 proved plus probable reserves are made with prior years, the comparison is with the established reserves of the prior year.

SUMMARY OF COMPANY INTEREST OIL AND GAS RESERVES – FORECASTED PRICES AND COSTS

January 1, 2004	Light and Medium Crude Oil (mmbbls)	Gas Liquids (mmbbls)	Natural Gas (mmcf)	Jan. 1, 2004 boe (mboe)	Jan. 1, 2003 boe (mboe)
Proved					
Developed producing	1,787	384	8,231	3,543	2,611
Developed non-producing	9	159	3,527	756	535
Undeveloped	285	–	367	347	227
Total proved	2,085	543	12,125	4,646	3,373
Probable	630	116	3,265	1,290	701
Total proved plus probable	2,712	659	15,390	5,936	4,074 (1)

Note: May not add due to rounding

(1) Represents proved plus 50% risked probable reserves at January 1, 2003

RESERVES RECONCILIATION – FORECASTED PRICES AND COSTS

	Crude Oil & NGL's (mmbbls)		Natural Gas (mmcf)		Equivalent (mboe)	
	Total Proved	Total Proved Plus Probable (1)	Total Proved	Total Proved Plus Probable (1)	Total Proved	Total Proved Plus Probable (1)
Opening Balance January 1, 2003	2,021	2,346	8,107	10,367	3,373	4,074
Drilling	739	921	7,162	8,981	1,933	2,418
Acquisitions	253	337	887	1,377	401	566
Dispositions	–	–	–	–	–	–
Revisions	(63)	92	(2,560)	(3,864)	(489)	(552)
Production	(325)	(325)	(1,471)	(1,471)	(570)	(570)
Closing Balance January 1, 2004	2,625	3,371	12,125	15,390	4,646	5,936

(1) Opening balance is based on proved plus 50% risked probable reserves

NET PRESENT VALUE OF RESERVES – FORECASTED PRICES AND COSTS

	Undiscounted	Discounted at			
($000s)		8%	10%	15%	20%
January 1, 2004 (1) (2)					
Proved					
Developed producing	51,288	38,555	36,528	32,501	29,481
Developed non-producing	13,387	9,050	8,394	7,130	6,220
Undeveloped	4,867	3,198	2,901	2,300	1,848
Total Proved	69,542	50,803	47,823	41,931	37,550
Probable	21,053	12,269	11,030	8,746	7,196
Total proved plus probable	90,596	63,072	58,853	50,677	44,746

Note: May not add due to rounding

(1) Utilizing Gilbert Laustsen Jung Associates Ltd. January 1, 2004, price forecast

(2) As required by NI 51-101, undiscounted well abandonment costs of $2.2 million for total proved reserves and $2.4 million for total proved plus probable reserves are included in the Net Present Value determination

PRICING ASSUMPTIONS – FORECASTED PRICES AND COSTS

The January 1, 2004, pricing forecasts presented below have been prepared by GLJ. These prices have been utilized in determining the reserves and cash flow forecasts above.

Year	Crude Oil WTI ($US/bbl)	Crude Oil Edmonton Light ($CDN/bbl)	Natural Gas AECO ($CDN/mmbtu)	Gas Sumas Spot ($US/mmbtu)	Inflation Rate (%/Year)
2004	29.00	37.75	5.85	4.55	1.5
2005	26.00	33.75	5.15	4.00	1.5
2006	25.00	32.50	5.00	3.90	1.5
2007	25.00	32.50	5.00	3.90	1.5
2008	25.00	32.50	5.00	3.90	1.5
2009	25.00	32.50	5.00	3.90	1.5
2010	25.00	32.50	5.00	3.90	1.5
2011	25.00	32.50	5.00	3.90	1.5
2012	25.00	32.50	5.00	3.90	1.5
2013	25.00	32.50	5.00	3.90	1.5
2014	25.00	32.50	5.00	3.90	1.5
Thereafter	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr

NET PRESENT VALUE OF RESERVES – CONSTANT PRICES AND COSTS

	Undiscounted	Discounted at			
($000s)		8%	10%	15%	20%
January 1, 2004 (1)					
Proved					
Developed producing	70,357	51,115	48,071	42,082	37,661
Developed non-producing	17,243	11,521	10,651	8,974	7,771
Undeveloped	6,083	4,075	3,716	2,987	2,434
Total proved	93,683	66,712	62,437	54,043	47,867
Probable	27,952	16,189	14,529	11,471	9,401
Total proved plus probable	121,635	82,901	76,966	65,513	57,268

Note: May not add due to rounding

PRICING ASSUMPTIONS – CONSTANT PRICES AND COSTS

Year	Crude Oil WTI ($US/bbl)	Crude Oil Edmonton Light ($CDN/bbl)	Natural Gas AECO ($CDN/mmbtu)	Gas Sumas Spot ($US/mmbtu)	Inflation Rate (%/Year)
2004	32.52	40.81	6.09	5.49	–

2003 FINDING, DEVELOPMENT AND NET ACQUISITION COSTS (FD&A)

2003	FD&A Exploration and Development Program before revisions	FD&A Exploration and Development Program with revisions	Total FD&A costs including future proved development costs	Total FD&A costs including future proved plus probable development costs
Capital expenditures ($000s)	26,697	26,697	29,397	30,897
Total proved reserve additions (mboe)	2,332	1,843	1,843	n/a
Total proved cost ($/boe)	11.45	14.49	15.95	n/a
Total proved plus probable reserve additions (mboe)	2,984	2,432	n/a	2,432
Total proved plus probable cost ($/boe)	8.95	10.98	n/a	12.70

RESERVE LIFE INDEX

The Company's reserve life index using average fourth quarter production of 1,757 boe/d is 7.2 years for total proved boe reserves and 9.3 years for total proved plus probable boe reserves.

RECYCLE RATIO

The recycle ratio is a key indicator for evaluating the Company's reinvestment program as a measure of the efficiency of capital investment. The ratio is determined by dividing the operating netback per barrel of oil equivalent by the current year's reserves finding, development and acquisition costs.

2003	$/boe	Recycle Ratio
Operating netbacks	$20.53	
Current year FD&A cost		
Proved	$15.95	1.3
Proved plus probable	$12.70	1.6

NET ASSET VALUE

($000s, except per share)

2003	Forecasted Prices And Costs	Constant Prices And Costs
Reserves (discounted at 8% before income tax)		
Proved	50,803	66,712
Probable	12,269	16,189
Total proved plus probable	63,072	82,901
Undeveloped land, seismic and other	6,500	6,500
Long-term debt	(7,510)	(7,510)
Working capital (deficiency)	(4,416)	(4,416)
Net asset value	57,646	77,475
Common shares outstanding (000s)	16,978	16,978
Net asset value ($/share)	$3.40	$4.56

LIQUIDITY AND CAPITAL RESOURCES

The Company had a revolving demand loan facility for up to a maximum of $17.3 million, with a Canadian financial institution at December 31, 2003. The Company recorded a working capital deficiency of $4.4 million and an outstanding bank loan of $7.5 million at December 31, 2003, (net debt of $11.9 million) compared with a working capital deficiency of $2.5 million and outstanding bank loan of $8.9 million (net debt $11.4 million) at December 31, 2002. Subsequent to year-end, the Company's loan facility was increased to $24 million.

During 2003, the Company issued 2,772,490 shares for gross proceeds of $12,267,330 which was used to assist with the funding of the capital program. On March 25, 2004, the Company closed a private placement equity offering of 2,532,500 shares at $4.75 per share for gross proceeds of $12,029,375.

On an ongoing basis, the Company will typically utilize three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt where deemed appropriate and new equity issues if available on appropriate terms. When financing corporate acquisitions, the Company may also assume certain future liabilities. In addition, the Company may adjust its capital expenditure program, depending on the commodity price outlook.

OUTLOOK

The industry continues to be very competitive with the cost of land and services remaining high. With increased commodity prices pushing up industry cash flows, we are experiencing greater competition for quality drilling opportunities. Notwithstanding, the Company has currently identified over 30 drilling prospects for 2004. Of these, 11 (4.85 net) wells have been drilled in the first quarter of 2004 resulting in 4 (1.3 net) gas wells, 5 (2.75 net) oil wells, 1 (0.4 net) dry and abandoned and 1 (0.4 net) standing well. Successful drilling in the last quarter of 2003 and early 2004 provides the Company with a solid risk balanced portfolio of drilling opportunities focused on high-quality reserves. The drilling program will continue to focus on high-quality, multi-zone natural gas and light oil targets in our West Central focus region and light oil projects in Southeast Saskatchewan. The Company also intends to pursue complementary property or corporate acquisitions that will enhance the value of the Company.

Forward Looking Statements – Certain information regarding Bear Creek Energy Ltd. set forth in this document, including Management's assessment of Bear Creek Energy Ltd.'s future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Bear Creek Energy Ltd.'s control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, current fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Bear Creek Energy Ltd.'s actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Bear Creek Energy Ltd. will derive therefrom.

Management's Report

Management is responsible for the preparation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles and for ensuring that all other financial information presented in this report is consistent with the consolidated financial statements. Management has established and maintains a system of internal controls, which are designed to provide assurance that assets are managed efficiently and to facilitate the preparation of reliable and timely financial information.

Ernst & Young LLP were appointed as independent auditors by the Shareholders of the Company and have examined the consolidated financial statements for the year ended December 31, 2003. The Audit Committee has reviewed these statements with Management and the auditors and has reported to the Board of Directors. The Board of Directors has approved the consolidated financial statements.

Russell J. Tripp
President and Chief Executive Officer

Alan Steele

R. Alan Steele
Vice President, Finance and Chief Financial Officer

April 16, 2004

Auditors' Report

To the Shareholders of Bear Creek Energy Ltd.

We have audited the balance sheets of Bear Creek Energy Ltd. as at December 31, 2003 and 2002 and the statements of net income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's Management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by Management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended, in accordance with Canadian generally accepted accounting principles.

Ernst + Young LLP

Chartered Accountants
Calgary, Canada

April 2, 2004

Consolidated Balance Sheets

As at December 31	2003	2002
	$	$
ASSETS *[note 5]*		
Current		
Accounts receivable *[note 8]*	4,870,344	1,925,218
Prepaids and deposits	63,414	74,433
	4,933,758	1,999,651
Property and equipment *[note 3]*	57,782,118	38,888,713
	62,715,876	40,888,364
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	9,349,265	4,519,263
Bank operating loan *[note 5]*	7,509,862	8,900,355
	16,859,127	13,419,618
Future income taxes *[note 7]*	4,808,705	3,249,323
Future site restoration	404,126	107,652
	22,071,958	16,776,593
Commitments *[notes 8 and 9]*		
Shareholders' equity		
Share capital *[note 6]*	39,053,715	23,855,505
Contributed surplus *[note 6]*	74,705	–
Retained earnings	1,515,498	256,266
	40,643,918	24,111,771
	62,715,876	40,888,364

See accompanying notes

On behalf of the Board:

M A Lambert

Martin A. Lambert
Chairman of the Board and Director

M Hislop

Martin Hislop
Director and Chairman, Audit Committee

Consolidated Statements of Net Income and Retained Earnings

For the years ended December 31	2003	2002
	$	$
REVENUE		
Petroleum and natural gas	20,772,562	12,814,683
Royalties, net of Alberta Royalty Tax Credit	(5,020,247)	(3,220,223)
Interest	6,546	–
	15,758,861	9,594,460
EXPENSES		
Operating	4,047,578	2,546,481
General and administrative	2,894,124	1,734,569
Interest	506,933	421,471
Depletion, depreciation and site restoration	6,974,704	4,164,846
	14,423,339	8,867,367
Income before income taxes	1,335,522	727,093
Income tax *[note 7]*		
Current	97,942	91,573
Future (recovery)	(21,652)	87,810
	76,290	179,383
Net income	1,259,232	547,710
Retained earnings (deficit), beginning of year	256,266	(291,444)
Retained earnings, end of year	1,515,498	256,266
Net income per share *[note 6]*		
Basic	0.09	$0.05
Diluted	0.09	$0.05

See accompanying notes

Consolidated Statements of Cash Flows

For the years ended December 31	2003	2002
	$	$
OPERATING ACTIVITIES		
Net income (loss)	1,259,232	547,710
Add (deduct) items not requiring cash:		
Depletion, depreciation and site restoration	6,974,704	4,164,846
Stock-based compensation expense *(note 6)*	74,705	–
Future income tax expense *(note 7)*	(21,652)	87,810
Funds provided by operations	8,286,989	4,800,366
Site restoration expenditures	(6,549)	–
Change in non-cash working capital *(note 10)*	5,934,866	2,607,337
Cash provided by operations	14,215,306	7,407,703
FINANCING ACTIVITIES		
Increase in bank operating loan	(1,736,553)	1,977,635
Issue of common shares for cash, net of costs	11,414,335	8,343,097
Cash provided by financing activities	9,677,783	10,320,732
INVESTING ACTIVITIES		
Acquisition of property and equipment	–	–
Expenditures on property and equipment	(19,938,295)	(18,454,435)
Cash expended on business combination *(note 3)*	(840,794)	–
Change in non-cash working capital *(note 10)*	(3,114,000)	726,000
Cash used in investing activities	(23,893,089)	(17,728,435)
Cash, beginning and end of year	–	–

See accompanying notes

Notes to Consolidated Financial Statements

1. BASIS OF PRESENTATION

Bear Creek Energy Ltd. (the "Company" – formerly Millennium Energy Inc.) was incorporated under the Business Corporations Act of Alberta and completed a business combination with Crossfield Gas Corp., a private company on July 25, 2003. For accounting purposes this transaction has been treated as a reverse take over and as such, all historical references are those of Crossfield Gas Corp. The Company's primary business is the exploration for, and development and production and acquisition of, crude oil and natural gas in Western Canada. The Company is listed on the Toronto Stock Exchange ("TSX") under the symbol "BCK".

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company have been prepared by Management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of financial statements for a period involves the use of estimates and approximations, which have been made using careful judgment. The consolidated financial statements have, in Management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

Property and equipment

Petroleum and natural gas properties and production equipment

The Company follows the full cost method of accounting for its petroleum and natural gas properties and related facilities in accordance with the guideline issued by The Canadian Institute of Chartered Accountants whereby all costs related to the acquisition of, exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in a Canadian cost centre and charged to income as set out below. Such costs include lease acquisition, drilling, geological and geophysical expenditures, lease rentals on non-producing properties, equipment costs and overhead expenses directly related to exploration and development activities. No indirect general and administrative costs have been capitalized.

Proceeds from disposal of properties will normally be applied as a reduction of the cost of the remaining assets, except when such a disposal would alter the depletion and depreciation rate by more than 20%, in which case a gain or loss will be recorded.

Depletion and depreciation

Depletion of petroleum and natural gas properties and depreciation of production equipment is provided using the unit-of production method based on estimated proved petroleum and natural gas reserves as determined by independent engineers. The relative amounts of oil and gas production are converted at a ratio of six thousand cubic feet of gas to one barrel of oil. In determining its depletion base, the Company excludes costs of acquiring and evaluating unproved properties until it is determined whether proven reserves are attributable to the properties or impairment occurs and includes an estimate of future costs to be incurred in developing proven reserves.

Office furniture and fixtures

Office furniture and fixtures are carried at cost and depreciated over the estimated useful lives of the assets at a rate of 20% per annum calculated on a declining balance basis. Depreciation is charged at half rates in the year of acquisition.

Ceiling test

The Company applies a ceiling test to the net carrying value of petroleum and natural gas properties to ensure that such costs do not exceed the estimated amount ultimately recoverable. This amount is the aggregate of estimated future net revenues from production of proven reserves and the cost of unproved properties, net of an impairment allowance, less future estimated production expenses, general and administrative expenses, financing expenses, estimated future abandonment and site restoration costs and income taxes. Future net revenues are estimated using year-end wellhead prices and costs without escalation or discounting, and the income tax, capital tax and Alberta royalty tax credit legislation in effect at year-end. Any reduction in value, as a result of the ceiling test, is charged to operations.

Notes to Consolidated Financial Statements

Future site restoration

The estimated cost of future abandonment and site restoration is based upon the current costs and anticipated method and extent of site restoration in accordance with existing legislation and industry practice. The annual charge, provided for on a unit of production basis, is accounted for as an expense as part of depletion, depreciation and site restoration. Actual abandonment and site restoration expenditures are charged to the accumulated provision as incurred.

Measurement uncertainty

The amounts recorded for depletion and depreciation of property and equipment and the provision for future site restoration costs and the ceiling test calculation are based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

Joint operations

Substantially all of the Company's exploration and development activities are conducted jointly with others and, accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

Flow-through shares

The Company has financed a portion of its exploration and development activities through the issuance of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits to the Company, the carrying value of the shares issued is reduced by the tax effect of the tax benefits renounced to subscribers. For flow-through share issuances in 2002, the tax effect of the renouncement was recorded when the corresponding exploration and development expenditures were renounced and incurred.

In 2003, the Company prospectively adopted the recommendation of the Emerging Issues Committee ("EIC") of the CICA. EIC 146 requires the recognition of the foregone tax benefit at the time of renouncement, provided there is reasonable assurance that the expenditures will be incurred.

Income taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change becomes substantively enacted.

Financial instruments

The Company periodically enters into commodity price derivative instruments to reduce the Company's exposure to adverse fluctuations in commodity prices in order to protect future cash flow used to finance the Company's capital expenditure program. No contracts are entered into for trading or speculative purposes. Gains and losses relating to commodity price derivative instruments that meet hedge criteria are recognized as part of petroleum and natural gas revenue concurrently with the hedged transaction.

The Company's policy is to formally designate each commodity price derivative instrument as a hedge of a specifically identified future revenue stream. The Company believes the commodity price derivative instruments are effective as hedges, both at inception and over the term of the instrument, as the term to maturity, the notional amount and the commodity price basis in the instruments all match the terms of the future revenue stream being hedged.

Realized and unrealized gains or losses associated with the commodity price derivative instruments, which have been terminated or cease to be effective prior to maturity, are deferred as other current, or non-current, assets or liabilities on the balance sheet, as appropriate and recognized in earnings in the period in which the underlying hedged transaction is recognized. In the event that a

designated hedged item is sold, extinguished or matures prior to the termination of the related commodity price derivative instrument, any realized or unrealized gain or loss on such derivate instrument is recognized in earnings.

Stock-based compensation

The Company has a stock-based compensation plan, which is described in Note 6. As of January 1, 2003, the Company adopted a new accounting standard on stock-based compensation. As permitted, under the standard, the Company has elected to prospectively adopt the fair value method of accounting for stock options. Stock option expense is recorded as general and administrative expense for all options granted on or after January 1, 2003, with a corresponding increase recorded to contribute surplus. No compensation expense is recorded for stock options awarded and outstanding prior to adoption of the new accounting standard. The fair values of options granted are estimated at the date of grant using the Black-Scholes valuation model. Consideration paid by employees or directors on the exercise of stock options is credited to share capital.

Per share amounts

The Company utilizes the treasury stock method in the determination of diluted per share amounts. Under this method, the diluted weighted average number of shares is calculated assuming the proceeds that arise from the exercise of outstanding, in the money options are used to purchase common shares of the Company at their average market price for the period.

3. BUSINESS COMBINATION

On July 25, 2003, by plan of arrangement ("Arrangement"), Millennium Energy Inc. ("Millennium") acquired all the issued and outstanding shares of Crossfield Gas Corp. ("Crossfield"), a private oil and natural gas company. In addition, the 2,791,333 Crossfield options not exercised were converted into Millennium options. Immediately following the acquisition, Millennium consolidated its shares on a one for 15 basis and changed its name to Bear Creek Energy Ltd.

As a result of the Arrangement, the former Shareholders of Crossfield acquired control of Millennium. Accordingly, the transaction has been accounted for as a reverse takeover whereby Crossfield was deemed to be the acquirer of Millennium for accounting purposes. Comparative information presented in these consolidated financial statements is the information of Crossfield.

The acquisition has been accounted for using the purchase method with the results of operations included in the consolidated financial statements from the closing date of the acquisition. The estimated fair value of the acquisition was $5,918,371 based upon the issuance of 1,989,415 shares. The determination of the $2.97 per share value was based upon the fair value of Crossfield's net assets at the date of the acquisition. The fair value of the purchase consideration has been allocated to Bear Creek's assets and liabilities as follows:

Calculation of Purchase Price	$
Fair value of shares issued *(note 6)*	5,918,371
Transaction costs	840,794
	6,759,165

Allocation of Purchase Price:	
Property and equipment	5,794,089
Working capital	924,969
Future income tax benefit	553,463
Bank debt	(346,059)
Future site restoration and abandonment costs	(167,297)
	6,759,165

In October 2003, the Company swapped its obligation and rights to the Columbia assets acquired as part of the Millennium acquisition for a 2% gross overriding royalty on the property with another public company. Millennium had an outstanding letter of credit

relating to the commitment to drill on the Columbia property, which the Company recognized as a liability in the initial purchase price allocation. Through the swap of these assets, the Company eliminated its obligation and therefore adjusted the purchase price allocation to eliminate the liability of $455,000 with a corresponding reduction to the value allocated to property and equipment. In addition, upon finalization of the Millennium tax returns, there was an increase in the tax pools, further reducing the value allocated to property and equipment by $553,463.

The Company retains the right for up to 18 months after the spudding of the first Columbia well to convert the gross overriding royalty to either a 10% working interest, or to 1 million shares of the public company. As at December 31, 2003, the drilling of the first commitment well had not commenced. The drilling of this well may not encounter economic reserves at which time the gross override may have no future value.

4. PROPERTY AND EQUIPMENT

2003	Cost $	Accumulated Depreciation $	Net Book Value $
Petroleum and natural gas properties and production equipment	68,509,199	10,826,418	57,682,781
Office furniture and fixtures	178,386	79,049	99,337
	68,687,585	10,905,467	57,782,118

2002	Cost $	Accumulated Depreciation $	Net Book Value $
Petroleum and natural gas properties and production equipment	42,787,631	4,016,199	38,771,432
Office furniture and fixtures	167,670	50,389	117,281
	42,955,301	4,066,588	38,888,713

The Company did not capitalize any indirect general and administrative expenditures related to acquisition, exploration and development activities in 2003 or 2002. At December 31, 2003, costs of $3.9 million (2002 – $1.3 million) related to unproven properties have been excluded from the depletion calculation.

For the year ended December 31, 2003, the Company charged $135,725 (2002 – $107,652) to expense for future site restoration.

5. BANK OPERATING LOAN

The Company has a $17.3 million revolving production loan facility with a Canadian financial institution that bears interest at its prime rate plus 0.25%. A general assignment of assets and a continuing debenture in the amount of $30 million has been pledged as collateral for loans under the facility. The Company has extended a $420,000 letter of guarantee to a provider of gas transportation services.

The terms of the banking arrangement allow for the financial institution to apply all cash balances against the outstanding line of credit at any time and as such the Company nets any cash balances in our account at a reporting period against the bank operating loan.

At December 31, 2003, the effective interest rate on the amount outstanding under the facility was 4.75 % (2002 – 5.0%). Cash interest paid during the year was $500,387 (2002 – $290,913).

6. SHARE CAPITAL

Authorized

Unlimited number of voting common shares with no par value

Issued

	Number of Shares	$
Balance, December 31, 2001	9,203,580	18,673,921
Issue of warrants for cash *(a)*	2,856,000	8,500,000
Issue of common shares for cash *(b)*	156,820	240,029
Tax benefits renounced related to flow-through shares *(c)*	–	(3,328,701)
Share issue costs, net of tax benefit of $167,188	–	(229,744)
Balance, December 31, 2002	12,216,400	23,855,505
Issue of flow-through shares for cash *(d)*	1,210,962	6,090,015
Issue of common shares for cash *(e)*	1,510,962	6,030,015
Shares issued on acquisition of Millennium *(note 3)*	1,989,415	5,918,371
Exercise of stock options	50,566	147,300
Tax benefits renounced related to flow-through shares *(d)*	–	(2,482,092)
Share issue costs, net of tax benefit of $347,596	–	(505,399)
Balance, December 31, 2003	16,978,305	39,053,715

(a) In August, 2002, the Company issued 2,856,000 special warrants for gross proceeds of $8,500,000. The special warrants were convertible into common shares at no additional cost to the warrant holder and have been included as a component of share capital. At December 31, 2003, all warrants have been converted into common shares.

(b) In February, 2002, the Company issued 16,800 common shares for gross proceeds of $40,000, in April, 2002, 105,013 common shares were issued for gross proceeds of $150,019 and in June, 2002, 35,007 common shares were issued for gross proceeds of $50,010.

(c) In October and December 2001, the Company issued 7,185,750 and 2,950,000 flow-through common shares for gross proceeds of $4,452,900 and $3,450,000, respectively. In accordance with the terms of the Company's flow-through share offerings, and pursuant to certain provisions of the Income Tax Act (Canada), the Company committed to renounce, for income tax purposes, exploration and development expenditures to the purchasers of its flow-through shares. During 2001, the Company renounced $5,522,900 and the expenditures were incurred in 2002. The entire tax benefit forgone from these renunciations was applied to share capital in 2002.

(d) In March, September and December, 2003, the Company issued 10,962, 400,000 and 800,000 flow-through common shares for gross proceeds of $30,015, $2,020,000 and $4,040,000, respectively. In accordance with the terms of the Company's flow-through share offerings, and pursuant to certain provisions of the Income Tax Act (Canada), the Company committed to renounce, for income tax purposes, Canadian Cumulative Exploration expenditures to the purchasers of its flow-through shares. During 2003, the Company renounced the full $6,090,015 of expenditures and recognized the forgone tax benefit in share capital.

As at December 31, 2003, the Company has incurred $2,590,015 of the 2003 renunciation with $3,500,000 remaining to be incurred in 2004.

(e) In April and August, 2003, the Company issued 10,962 and 1,500,000 common shares for gross proceeds of $30,015 and $6,000,000 respectively.

The Company has 333,333 warrants outstanding which are each convertible into a Bear Creek common shares at a price of $5.40 per warrant. These warrants are not convertible until July 25, 2004, and expire on July 24, 2006.

Stock-based Compensation

The Company has established a stock-option plan whereby options may be granted to the Company's directors, officers and employees for up to 950,000 common shares. In addition there are 1,045,100 former Crossfield options and 104,200 former Millennium options outstanding at December 31, 2003, from former plans that have been brought forward into the Company. The exercise price of each option equals the market price of the Company's stock on the date of the grant. An option's maximum term is 5 years and the options vest equally over 3 years beginning on the first anniversary of the date the option is granted. The following is a continuity of stock options outstanding for which shares have been reserved:

Stock Options	Options	Weighted Average Exercise Price ($)
December 31, 2001	–	–
Granted	1,158,360	2.98
Exercised	–	–
December 31, 2002	1,158,360	2.98
Conversion of Millennium options (note 3)	118,200	2.67
Granted	599,500	3.63
Exercised – ex Millennium	(53,900)	2.89
Cancelled	(199,360)	2.98
December 31, 2003	1,622,800	3.20

The following summarizes information about stock options outstanding at December 31, 2003:

Grant Price	Number Outstanding	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number Exercisable (Vested)	Weighted Average Exercise Price (Vested)
$2.25 – $3.00	1,134,300	3.10	$2.94	395,260	2.87
$3.15 – $3.75	15,000	0.5	$3.68	15,000	3.68
$3.75 – $4.00	473,500	4.8	$3.80	–	–
	1,622,800	3.5	3.20	410,260	2.90

In September, 2003, the CICA amended Section 3870 "Stock-based compensation and other stock-based payments" to be effective for fiscal years beginning on or after January 1, 2004, with earlier adoption encouraged. In the fourth quarter of 2003, and effective January 1, 2003, the Company adopted the amended standard which requires the use of the fair value method for valuing stock options grants. Under this method, compensation cost, attributable to share options granted to employees or directors is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus on the Company's balance sheet. Pursuant to the transition rules, the expense recognized applies to stock options granted on or after January 1, 2003. The impact of the adoption of this amended standard is $74,705 for 2003.

The Company has not incorporated an estimated forfeiture rate for stock options that will not vest; rather the Company accounts for actual forfeitures as they occur.

The fair value of each common share option granted was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions: the Company used a risk-free interest rate of 3.96%, an expected life of 4 years, expected volatility of 38% and an expected dividend yield of 0%. These assumptions resulted in a weighted average fair value for options granted in 2003 of $1.26 per option.

Per Share Amounts

The following table summarizes the common shares used in calculating net income per share.

	Year Ended December 31	
Weighted Average Common Shares	2003	2002
Basic	13,820,707	10,445,289
Diluted	14,130,271	10,445,289

7. INCOME TAXES

Income taxes recorded in the statements of net income and retained earnings differ from the tax calculated by applying the combined Canadian federal and provincial corporate income tax rate to income before income taxes as follows:

	2003 $	2002 $
Computed income tax expense at 40.75% (2002 – 42.12%)	544,225	306,252
Add (deduct) income tax effect of:		
Non-deductible Crown charges, net of ARTC	1,195,160	973,741
Resource allowance	(946,918)	(728,916)
Benefit of attributed Crown royalty income	(139,053)	(94,117)
Benefit of tax rate changes	(687,688)	–
Benefit of pools not previously recognized	–	(369,210)
Other	12,622	60
Future income tax expense (recovery)	(21,652)	87,810
Large corporation tax	97,942	91,573
Income tax	76,290	179,383

The components of the future income tax liability are as follows:

	2003 $	2002 $
Difference between tax basis and reported amounts for depreciable assets	6,522,966	4,350,805
Benefit of non-capital losses	(860,408)	(661,057)
Benefit of attributed Crown royalty income	(254,329)	(94,117)
Share issue costs	(459,576)	(312,301)
Provision for future site restoration	(139,948)	(34,007)
Future income tax liability	4,808,705	3,249,323

The Company's future income tax provision and the future tax liability were reduced by approximately $0.9 million (2002 – $0.4 million) as a result of changes to federal and Alberta income tax legislation which will reduce the statutory corporate income tax rates on income earned from resource activities in the current and future periods. The changes, which reduced the federal rate on resource income by 7%, provide for the deduction of Crown charges and eliminate the resource allowance by 2007. The Alberta rate was reduced by 0.5%. Effective June, 2003, the combined federal and Alberta corporate tax rate declined 1.25%, thereby reducing the current period's effective tax rate.

Taxes paid approximate large corporation tax expense for each of the years ended December 31, 2003 and 2002.

8. FINANCIAL INSTRUMENTS

(a) Fair value

Financial instruments recognized on the balance sheet consist mainly of accounts receivable, accounts payable and accrued liabilities and a bank operating loan. As at December 31, 2003 and 2002, there are no significant differences between the carrying amounts of these instruments and their estimated fair values.

As at December 31, 2003, the Company had the following hedges outstanding:

Crude Oil Swap Referenced to WTI Index	Quantity/Day	Price/Barrel
January 1, 2003 – December 31, 2003	250 barrels	US$25.67
January 1, 2004 – June 30, 2004	200 barrels	US$26.00 – $31.55 Costless collar

Subsequent to year-end the Company has entered into the following hedge agreement.

Crude Oil Swap Referenced to WTI Index	Quantity/Day	Price/Barrel
July 1, 2004 – December 31, 2004	200 barrels	US$30.00 – $35.00 Costless collar

(b) Credit risk

Oil and gas marketing entities account for fewer than 40% of the Company's accounts receivable balance. The Company generally extends unsecured credit to these companies, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and accordingly may impact the Company's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which it extends credit.

The Company has not previously experienced any material credit losses on the collection of receivables.

9. COMMITMENTS

Minimum lease payments

The Company has entered into lease agreements for office space to April 30, 2006. The future minimum lease payments are:

	$
2004	192,234
2005	192,234
2006	64,078
	448,546

10. NON-CASH WORKING CAPITAL

A summary reconciliation of non-cash working capital changes is as follows:

	2003	2002
Increase in accounts receivable	(2,945,126)	(1,024,231)
Decrease in prepaids and deposits	11,019	(33,792)
Increase in accounts payable and accrued liabilities	4,830,003	4,391,359
	1,895,896	3,333,336
Millennium working capital assumed (note 3)	924,969	–
	2,820,865	3,333,336
Non-cash working capital – operating activities	5,934,865	2,607,336
Non-cash working capital – investing activities	(3,114,000)	726,000
	2,820,865	3,333,336

11. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the presentation adopted in the current year.

Corporate Information

DIRECTORS

Martin A. Lambert (2) (3)
Chairman
Bear Creek Energy Ltd.
Partner, Bennett Jones LLP
Calgary, Alberta

Geoffrey A. Cumming (1) (4)
Vice Chairman
Gardiner Group Capital Ltd.
Auckland, New Zealand

Martin Hislop (1) (4)
Chief Executive Officer
APF Energy Ltd.
Calgary, Alberta

John A. Howard (5)
President, Lunar Enterprises Corp.
Calgary, Alberta

Garry Tanner (1) (2) (3)
Senior Vice President
and Chief Operating Officer
EnerPlus Resources Fund
Calgary, Alberta

Russell J. Tripp
President and Chief Executive Officer
Bear Creek Energy Ltd.
Calgary, Alberta

(1) Audit Committee
(2) Compensation Committee
(3) Reserves Committee
(4) Governance and Nominating Committee
(5) Nominated for election

OFFICERS

Russell J. Tripp, LL.B, P.Land
President and Chief Executive Officer

Neil G. Bokenfohr, B.Sc., P.Eng.
Vice President, Engineering

Douglas C. Hibbs, B.Sc., P.Geol
Vice President, Exploration

R. Alan Steele, CMA
Vice President, Finance & CFO

Korby Zimmerman, B.Comm., PLM
Vice President, Land

PROFESSIONAL STAFF

C.E. (Cal) Jaycock, B.Sc., P.Geol.
Senior Geologist

Elizabeth More, B.Sc., P.Geol.
Senior Geologist

Kelly Novakowski, B.Comm., CMA
Controller

Andrew Wiacek, M.Sc., P.Geoph.
Manager, Geophysics

Kenneth E. Wing, B.Sc., P.Eng.
Manager of Operations

CORPORATE OFFICE

Bear Creek Energy Ltd.
1240, 407 - 2nd Street S.W.
Calgary Alberta T2P 2Y3
Telephone: (403) 517-3700
Facsimile: (403) 517-3711
Website: www.bearcreekenergy.com

STOCK EXCHANGE LISTING

The Toronto Stock Exchange (TSX)
Symbol: BCK

BANKER

ATB Financial
239 - 8th Avenue S.W.
Calgary, Alberta T2P 1B9

SOLICITOR

Bennett Jones LLP
4500 Bankers Hall East
855 - 2nd Street S.W.
Calgary, Alberta T2P 4K7

AUDITOR

Ernst & Young LLP
1000, 440 - 2nd Avenue S.W.
Calgary, Alberta T2P 5E9

CONSULTING ENGINEERS

Gilbert Laustsen Jung
Associates Ltd.
4100, 400 - 3rd Avenue S.W.
Calgary, Alberta T2P 4H2

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bbl	barrel
bbl/d	barrels of oil per day
mbbls	thousand barrels
boe	barrels of oil equivalent*
boe/d	barrels of oil equivalent per day*
mboe	thousand barrels of oil equivalent*
mmboe	million barrels of oil equivalent*
mmbtu	million British thermal units
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
NGL	natural gas liquid
NPV	net present value
P+P	proved plus probable
WTI	West Texas Intermediate

*6 mcf of gas = 1 barrel of oil

Bear Creek Energy Ltd.
1240, 407 - 2nd Street S.W.
Calgary Alberta T2P 2Y3
Telephone: (403) 517-3700
Facsimile: (403) 517-3711
www.bearcreekenergy.com

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